Value of EV TOU for MA Customers

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Key Insights & Takeaways

The AGO analyzed the potential EV consumer savings associated with hypothetical TOU rate designs that time-varied different components of a residential retail bill.

Based on that analysis, AGO finds:

1. Many costs underlying retail charges have a time-varying dimension.
2. EV TOU can materially reduce EV charging cost without shifting costs to other customers (intra- or inter-class).
3. Benefits increase as fraction of costs with TOU treatment increases.
4. Extending TOU to T&D follows cost causation principles and enables meaningful benefits to municipal aggregations.

General Benefits of TOU Rates

- TOU rates can improve system efficiency, because they:
  - Provide actionable price signals to customers with meaningful flexible loads or loads which can be scheduled for low-cost periods.
  - Help reduce consumption at peak times, which drives a significant share of total system costs.
  - Allow for new, productive uses of electricity which are only cost-effective at rates below the *average* cost of electricity. Helps with electrification.
- Because EV customers have large, flexible loads that are reasonably price responsive, they are a good candidate for TOU rates.
  - EVs also unique because they reflect *new* system load.

Case Study Framework

Goal: Assess residential cost impact for EV TOU under four sample rates, and one flat rate, using hourly cost data for New England running 2014-2018.

1. Develop cost allocations to "shape" average costs into their time-varying equivalents.
2. Develop generic TOU specifications, with an increasing share of cost components subject to time-varying treatment.
3. Develop efficient, cost-based prices for each specification.
4. Calculate a typical bill for a household with and without EV load.
5. Assess efficiency of TOU rate, compared to flat and real-time rates.

Time-varying costs are found in Basic Service, Transmission, and Distribution Charges

Supplier charges embed wholesale market costs for energy, ancillary services, and capacity.

- Each of these products has cost which vary over time.
- Temporal attribution for wholesale market costs is easy because it is codified in the ISO-NE Tariff.
- For example, ISO-NE capacity tags (~10% of retail bills) are entirely allocated on highest system peak usage.
- Basic service also includes some costs which are time invariant (e.g. RPS).

Transmission costs (~13% of retail bills) are allocated to EDCs by ISO-NE, based on share of consumption in certain hours.

Distribution costs are not assessed in specific hours under current distribution tariffs but have a temporal dimension too.

- Already implicit in use of class non-coincident peak cost allocators in EDC Cost of Service Studies.

Time-varying costs are found in Basic Service, Transmission, and Distribution Charges (cont.)

BASIC SERVICE

- ISO-NE **energy** and most **ancillary services** costs vary every 5 minutes.
- ISO-NE **Forward Capacity Market** costs are allocated to load based on the system's peak hour.
  - Reducing consumption in the system peak hour, reduces LSE capacity costs for the full year-long Capacity Commitment Period. (Tariff III.13.7.5.5).
  - Thus, marginal cost of FCM costs is $0 in 8759 hours per year and approximately $90,000/MWh in one hour.
- Basic Service also includes other time-invariant costs (e.g. RPS, APS, SREC, CES; ISO-NE Self-Funding).

Time-varying costs are found in Basic Service, Transmission, and Distribution Charges (cont.)

TRANSMISSION

- The regional costs for transmission is allocated to EDCs based on their share of ISO-NE system demand during the peak hour of each month.
  - The current wholesale rate for transmission equals about $13,500/MW-month.
- Reducing demand on any/all monthly system peak reduces transmission costs for the EDC for the whole month.
  - Reducing demand outside of the monthly peak hour does not affect transmission costs.
- Thus, the marginal cost of transmission on the monthly peak hour equals ~$13,500/MWh and is zero otherwise.

Time-varying costs are found in Basic Service, Transmission, and Distribution Charges (cont.)

DISTRIBUTION

- Some distribution costs have time-varying components.
- Substations and transformers are generally sized for peak loads.
- Some costs, such as bill postage costs, are unlikely to be time-varying.
- Other distribution service charges like transition, decoupling, distributed solar, renewable energy and energy efficiency charges may not vary with time.
- For this analysis, AGO estimates that 25% of the distribution plant costs are time-varying and that 75% does not vary with time.
  - AGO assumes that the share of distribution costs which are time-varying are assigned to system monthly peak hours, like ISO-NE transmission costs.

AGO assumes a 23.9 ¢/kWh rate and consolidates charges into key categories

Residential Bill Component	Average Rate (¢/kWh)	Time Varying	Assumed Cost Incidence (See Appendix 1 for details)
Supplier (Basic Service)	**11.1**		
Energy	*4.7*	*Yes*	*Hourly Varying*
Capacity	*2.3*	*Yes*	*System Annual Peak Hour*
Ancillary Services, Green, & Other	*4.1*	*No*	*Equal in all Hours*
Distribution Charges	**12.8**		
Distribution Plant Charges	*6.4*	*Partial*	*25% System Monthly Peak Hours* *75% Equal in all Hours*
Other Distribution Services Charges	*3.3*	*No*	*Equal in all Hours*
Transmission Charge	**3.1**	*Yes*	*System Monthly Peak Hours*
Total	**23.9**		

AGO Typical Bills based on Annual Oversight Questions (2018). Basic Service partitioned based on observed energy and capacity costs.
Supplier “Other” includes RPS I, II, APS, SREC, CES
Distribution “Other” includes transition, decoupling, distributed solar, renewable energy and energy efficiency charges.

AGO created five sample TOU rate specifications, increasingly time-varying.

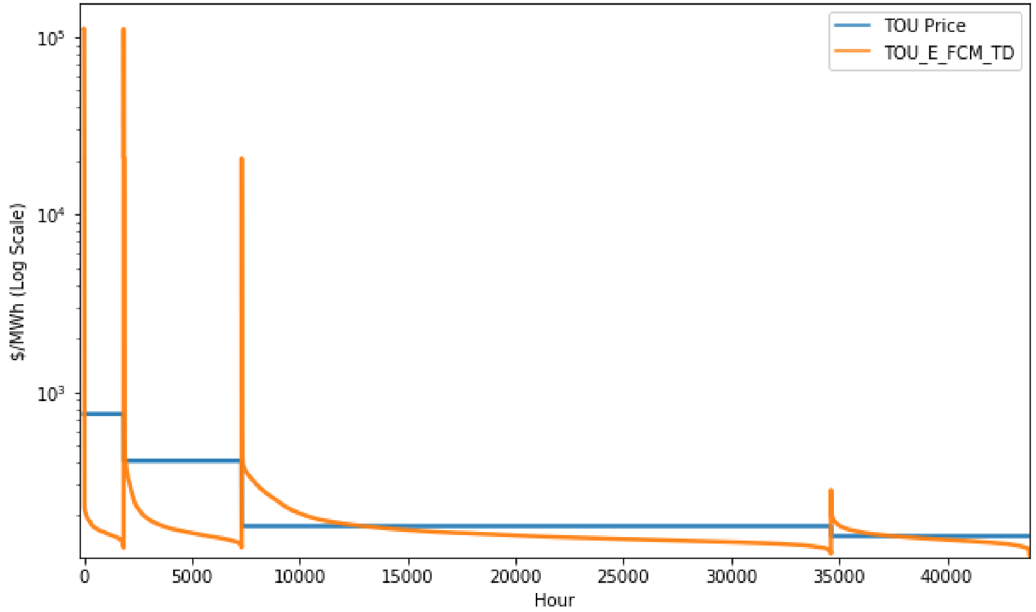
Cost Category with time-varying component (✓); otherwise flat, time-invariant cost (–)

Residential Bill Component	Average Rate (¢/kWh)	Flat	TOU Energy Only	TOU Basic Service	TOU BS + Dist.	TOU BS + T&D
Supplier (Basic Service)	**11.1**					
Energy	*4.7*	–	✓	✓	✓	✓
Capacity	*2.3*	–	–	✓	✓	✓
Ancillary Services, Green, & Other	*4.1*	–	–	–	–	–
Distribution Charges	**12.8**					
Distribution Plant Charges	*6.4*	–	–	–	✓	✓
Other Distribution Services Charges	*3.3*	–	–	–	–	–
Transmission Charge	**3.1**	–	–	–	–	✓
Total Rate (Average, cents/kWh)	**23.9**	**23.9**	**23.9**	**23.9**	**23.9**	**23.9**

TOU rates calculated using novel, cost-based algorithmic technique, ensuring efficiency.

- Algorithm identifies the seasons, periods, and prices which, when considered as a whole, minimizes the price deviations between the underlying hourly prices and the simplified TOU rate schedule.
  - Rate is based on total marginal cost.
  - Rates are *efficient* because they mirror underlying costs as closely as possible.
  - Rates ensure *revenue neutrality* for each cost category
  - Existing customer load is *indifferent* between the flat and TOU rates for existing household loads.
  - Method also lets you compare efficiency of alternative rates.
- Details of this technique provided in associated Whitepaper and are summarized in Appendix 2.

Sample Price Duration Curves for a 2-Season/2-Period Residential TOU



Results: Basic Service TOU (¢/kWh)

Residential Rate with TOU Basic Service and TOU Distribution	**Time varying component**	**Annual Average Rate (¢/kWh)**	**Summer** (Jun-Aug)		**Winter** (Sep-May)	
			On-Peak (HE 15-18)	**Off-Peak** (HE 19-14)	**On-Peak** (HE 16-21)	**Off-Peak** (HE 22-15)
Supplier (Basic Service)		**11.10**	**39.94**	**7.12**	**12.32**	**8.98**
Energy	✓	*4.70*	*4.59*	*3.02*	*6.08*	*4.88*
Capacity	✓	*2.30*	*31.25*	*0*	*2.14*	*0*
Ancillary Services, Green, & Other	–	*4.10*	*4.10*			
Distribution Charges		**9.70**	**9.70**			
Distribution Plant Charges	–	*6.40*	*6.40*			
Other Distribution Service Charges	–	*3.30*	*3.30*			
Transmission Charge	–	**3.10**	**3.10**			
Total Marginal Cost		**23.90**	**52.74**	**19.92**	**25.13**	**21.78**

Supplier "Other" includes RPS I, II, APS, SREC, CES

Distribution "Other" includes transition, decoupling, distributed solar, renewable energy and energy efficiency charges.

Results: Basic Service and Distribution TOU (¢/kWh)

Residential Rate with TOU Basic Service and TOU Distribution	**Time varying component**	**Annual Average Rate (¢/kWh)**	**Summer** (Jul-Sep)		**Winter** (Oct-Jun)	
			On-Peak (HE 17-20)	**Off-Peak** (HE 21-16)	**On-Peak** (HE 15-18)	**Off-Peak** (HE 19-14)
Supplier (Basic Service)		**11.10**	**41.24**	**7.25**	**13.05**	**9.00**
Energy	✓	*4.70*	*4.78*	*3.15*	*6.31*	*4.90*
Capacity	✓	*2.30*	*32.36*	*0*	*2.64*	*0*
Ancillary Services, Green, & Other	–	*4.10*	*4.10*			
Distribution Charges		**9.70**	**16.78**	**8.10**	**14.79**	**8.24**
Distribution Plant Charges	✓	*6.40*	*13.48*	*4.80*	*11.49*	*4.94*
Other Distribution Service Charges	–	*3.30*	*3.30*			
Transmission Charge	–	**3.10**	**3.10**			
Total Marginal Cost		**23.90**	**61.13**	**18.45**	**30.94**	**20.34**

Supplier "Other" includes RPS I, II, APS, SREC, CES

Distribution "Other" includes transition, decoupling, distributed solar, renewable energy and energy efficiency charges.

Results: Basic Service, Distribution, and Transmission TOU (¢/kWh)

Residential Rate with TOU Basic Service and TOU Distribution	Time varying component	Annual Average Rate (¢/kWh)	**Summer** (Jul-Sep)		**Winter** (Oct-Jun)	
			On-Peak (HE 17-20)	**Off-Peak** (HE 21-16)	**On-Peak** (HE 15-18)	**Off-Peak** (HE 19-14)
Supplier (Basic Service)		**11.10**	**41.24**	**7.25**	**13.05**	**9.00**
Energy	✓	*4.70*	*4.78*	*3.15*	*6.31*	*4.90*
Capacity	✓	*2.30*	*32.36*	*0*	*2.64*	*0*
Ancillary Services, Green, & Other	–	*4.10*	*4.10*			
Distribution Charges		**9.70**	**16.78**	**8.10**	**14.79**	**8.24**
Distribution Plant Charges	✓	*6.40*	*13.48*	*4.80*	*11.49*	*4.94*
Other Distribution Service Charges	–	*3.30*	*3.30*			
Transmission Charge	✓	**3.10**	**16.83**	**0**	**12.96**	**0.26**
Total Marginal Cost		**23.90**	**74.85**	**15.35**	**40.80**	**17.50**

Supplier "Other" includes RPS I, II, APS, SREC, CES
Distribution "Other" includes transition, decoupling, distributed solar, renewable energy and energy efficiency charges.

Results: Total Marginal Cost by Rate, Season & Period (¢/kWh)

Season	Period	Flat	TOU Energy Only	TOU Basic Service	TOU BS + Dist.	TOU BS + T&D
Summer	Peak	23.90	23.25	52.74	61.13	74.85
	Off-Peak	23.90	21.91	19.93	18.45	15.35
Winter	Peak	23.90	27.52	25.13	30.94	40.80
	Off-Peak	23.90	25.48	21.78	20.34	17.50
Annual Average (load-wtd.)		**23.90**	**23.90**	**23.90**	**23.90**	**23.90**

- Efficient TOU rates shift more cost into peak period.
  - TOU rates can have very high peak period prices because the system has very high prices in some hours.
- As time-varying treatment is extended to more cost categories, peak/off-peak differentials increase.
  - A TOU substitute for Basic Service has a 2.5:1 peak/off-peak ratio.
  - TOU on Basic Service and T&D cost categories yields a 5:1 ratio.

Results: Residential bills decline as more cost categories get TOU treatment.

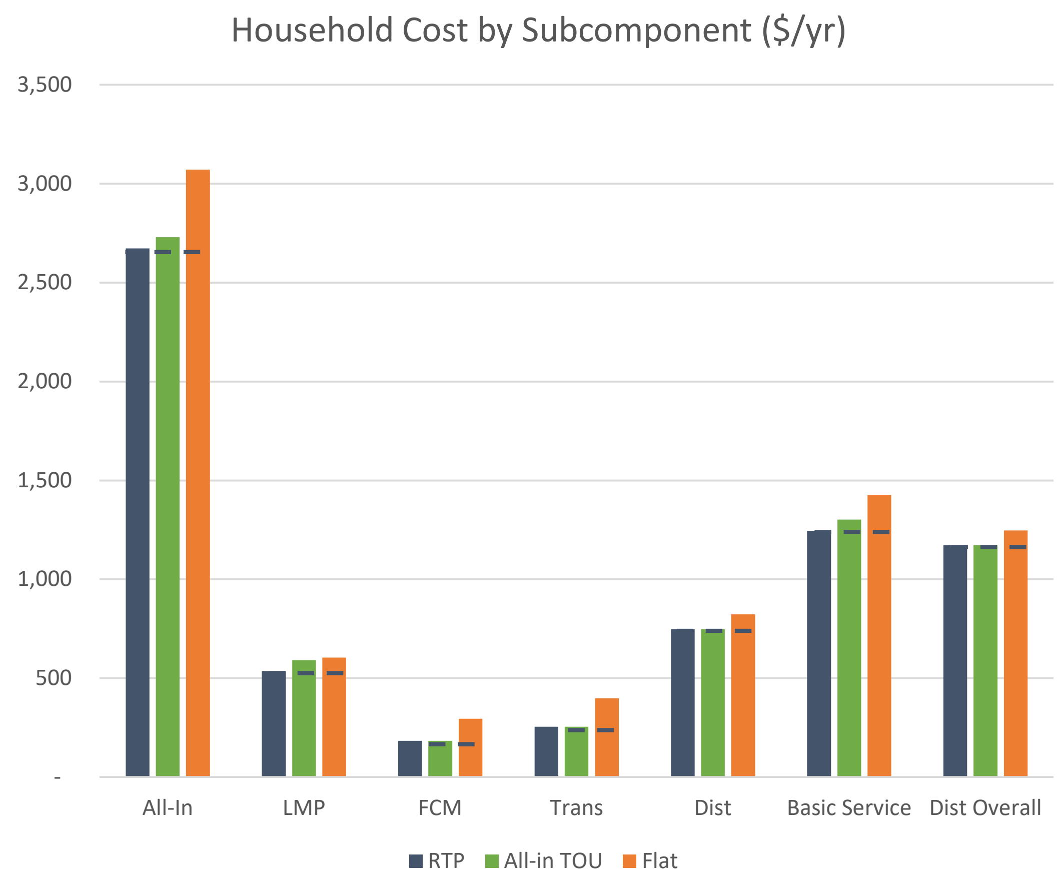
Season	Load Type	Flat	TOU Energy Only	TOU Basic Service	TOU BS + Dist.	TOU BS + T&D
Annual Cost ($/Year)	**Household** (7.9 MW/yr)	1,891	1,891	1,891	1,891	1,891
	EV (4.94 MW/yr)	1,182	1,126	1,053	981	838
	Total	3,073	3,018	2,944	2,873	2,729
EV Savings (vs. Flat Rate)	**$/Year**		**-$55**	**-$129**	**-$200**	**-$344**
	% of Cost		**-5%**	**-11%**	**-17%**	**-29%**

Notes

- Load profile calculated using residential data provided by National Grid in their Default Service RFPs. (https://www9.nationalgridus.com/energysupply/current_procurement.asp)
- EV charging is assumed to occur in off-peak hours.
  (Charging demand assumes 15,000 miles per year and a conversion efficiency of 3 miles/kWh.)

Results: TOU rates can be economically efficient and need not shift costs to other classes.

- AGO measures economic efficiency as TOU rate deviation from RT ideal.
- On a flat rate, an EV household would pay 15% more than the costs they incur on the system.
- On an BS and T&D TOU rate, an EV household would only pay 2% more than their share of system costs.
- Thus, TOU rates can accurately reflect underlying costs (meaning costs are not shifted to other customers).



Observations & Conclusions

- TOU rates can materially reduce charging costs.
  - All-in TOU rate can reduce costs by 30% (worth $2,000+ @ NPV 10%)
  - For point of reference, the MA MOR-EV rebate program offers up to $2,500.
- Reduced charging costs are the product of price-based TOU rates, not implicit subsidization from other customers.
  - EV customers still “overpaying” by about 2%.
- T&D TOU unlocks two-thirds of the overall value of all-in TOU rates.
- Results will vary based on specific cost allocation choices, but trends are consistent over a range of possible configurations.

Questions?

Other Observations on TOU Rate Design

TOU on Whole House vs EV Only

- The residential TOU rates outlined by the AGO can be applied to either the whole house or the EV with no change in modeled outcome.
  - Rates reflect marginal cost of serving residential loads; reasonable given small EV footprint compared to overall residential loads.
- If existing customer loads are reasonably price responsive, then household peak loads (and costs) may also fall under TOU rates.
  - If a significant share of household load is price responsive, additional checks required to ensure class revenue sufficiency.
- Might be non-revenue related reasons to prefer one configuration or another. (e.g., consumer preferences or metering costs)

Extending TOU to T&D costs enables participation by Municipal Aggregations.

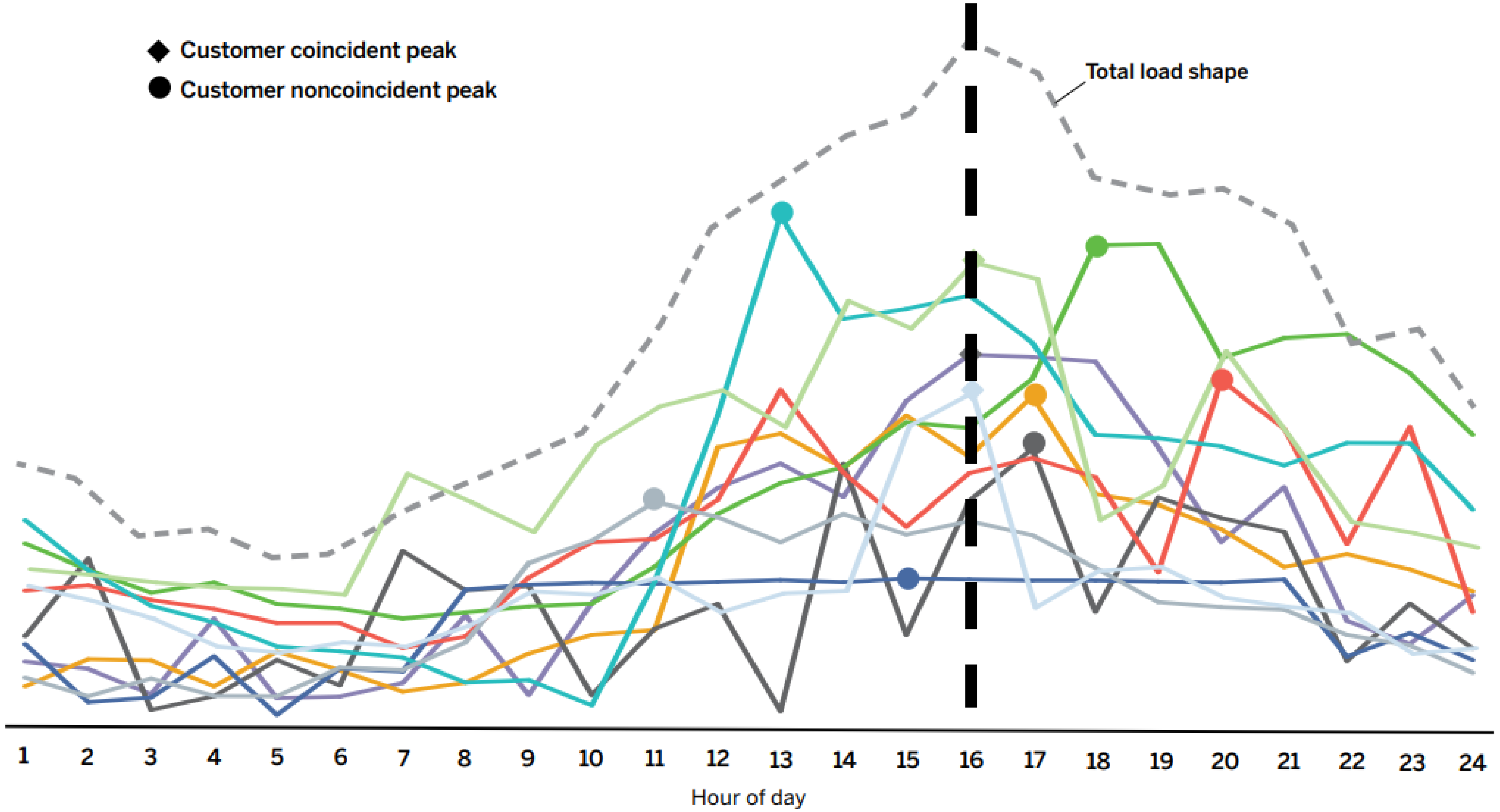
- Municipal aggregations replace Basic Service with an alternative provider of electricity supply.
  - Muni Ag. customers still pay delivery charges to EDCs.
- Aggregation participants have the energy and capacity portion of their rate “locked up” and would be unable to participate in any TOU substitute without losing the benefits offered by the Muni. Ag.
- Extending TOU to T&D costs would enable Muni. Ag. customers to benefit from rate reform, because it operates outside of supply contract.
- As noted in the AGO analysis, TOU on these T&D charges could save EV customers more than $200/year (about 62% of total possible benefit), by more accurately tracking the cost incidence of EV consumption.

Demand Charges unlikely to reflect incidence of most cost divers.

- Demand charges come in three main flavors:
  - **Coincident Peak (CP)** – which represent share of demand a customer used when the whole system peaks, in a given costing period (irrespective of whether that customer's demand is also peaking).
  - **Non-coincident Peak (NCP)** – which represent customer’s peak demand, in a given costing period (irrespective of total demand in the wholesale system).
  - **Peak Period** – which represent customer’s peak demand in a set of pre-defined “peak hours”
- Because a customer’s individual peak demand can occur at any time of day and not necessarily during the hour when system costs are greatest, the standard NCP demand charge does not generally reflect cost causation.
  - E.g., energy, capacity, transmission costs are not a function of NCP.
- CP demand charges are better aligned, because wholesale transmission and capacity costs are a function of CP demand (12 CP and 1 CP respectively).
  - CP harder to assess, because the specific peak hours are only known *post hoc*, so CP rates often rely on expected class CPs → near equivalent to TOU.
- Peak Period demand charges start to approximate TOU rates.

Aggregate peaks, not NCP, drives sizing of many distribution components.

Summer peak day load from 10 residential customers on one line transformer



Adapted from RAP's *Electric Cost Allocation for a New Era* (2020), Fig 17. Source: Confidential load research sample

In the example,

- Only three of the 10 customers peak at the group peak.
- CP is 14% lower than sum of individual peaks on this day.
- CP is 36% lower than sum of individual peaks across the month (not shown).

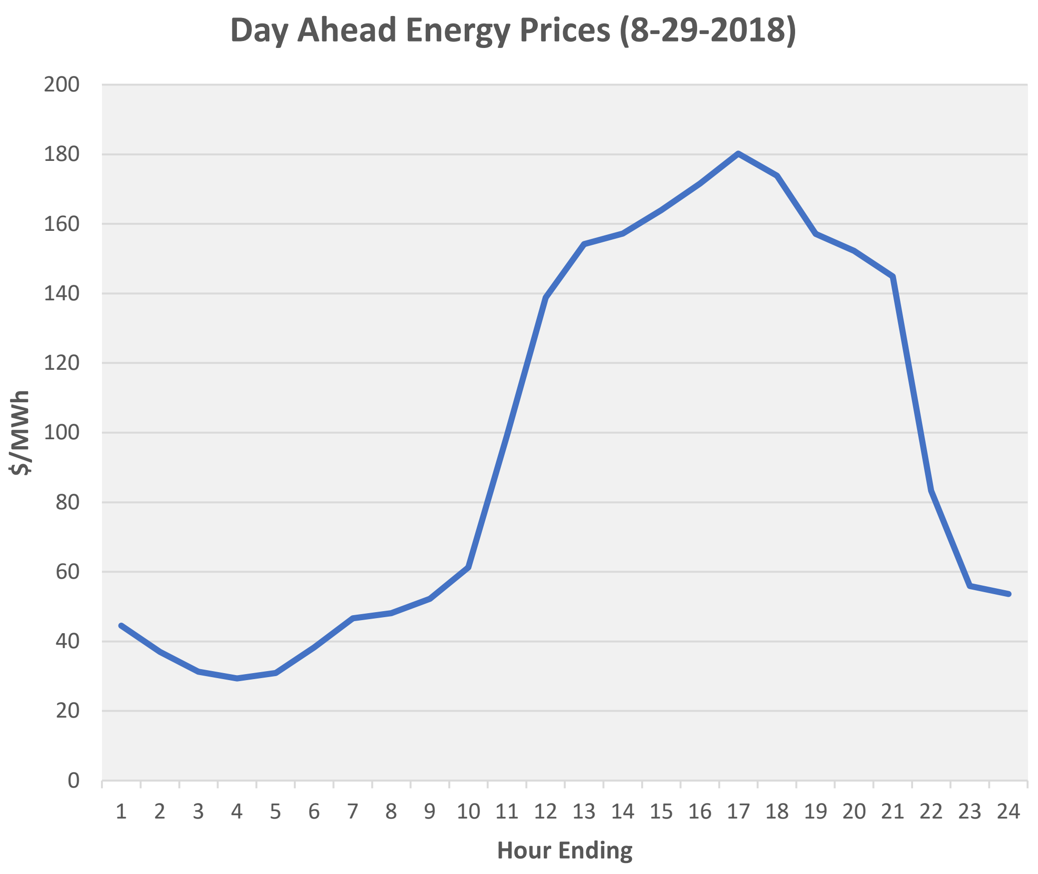
- -

- EV's might drive class/group peaks into nighttime charging hours but this cannot be assumed.
  - *Still won't affect Capacity or Transmission costs unless EV load starts inducing new system peaks.*

Appendix 1: Marginal Cost of Bill Components

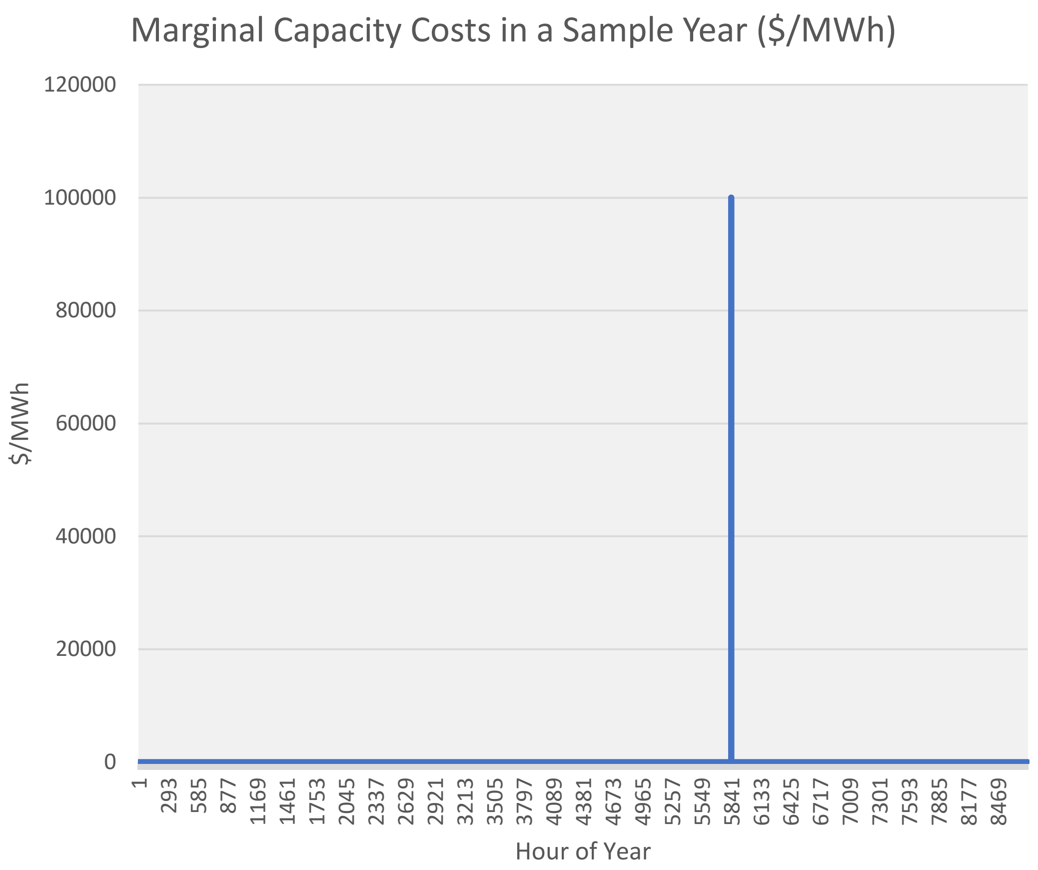
Wholesale energy costs vary hourly.

- Energy costs are part of basic service and are sourced from ISO-NE energy market.
- ISO-NE energy costs, or Locational Marginal Prices ("LMP") vary hourly in the day-ahead market.
  - Also a real-time market where prices are set every five minutes.
- Over 2014-2018, average cost of energy totaled $47/MWh.



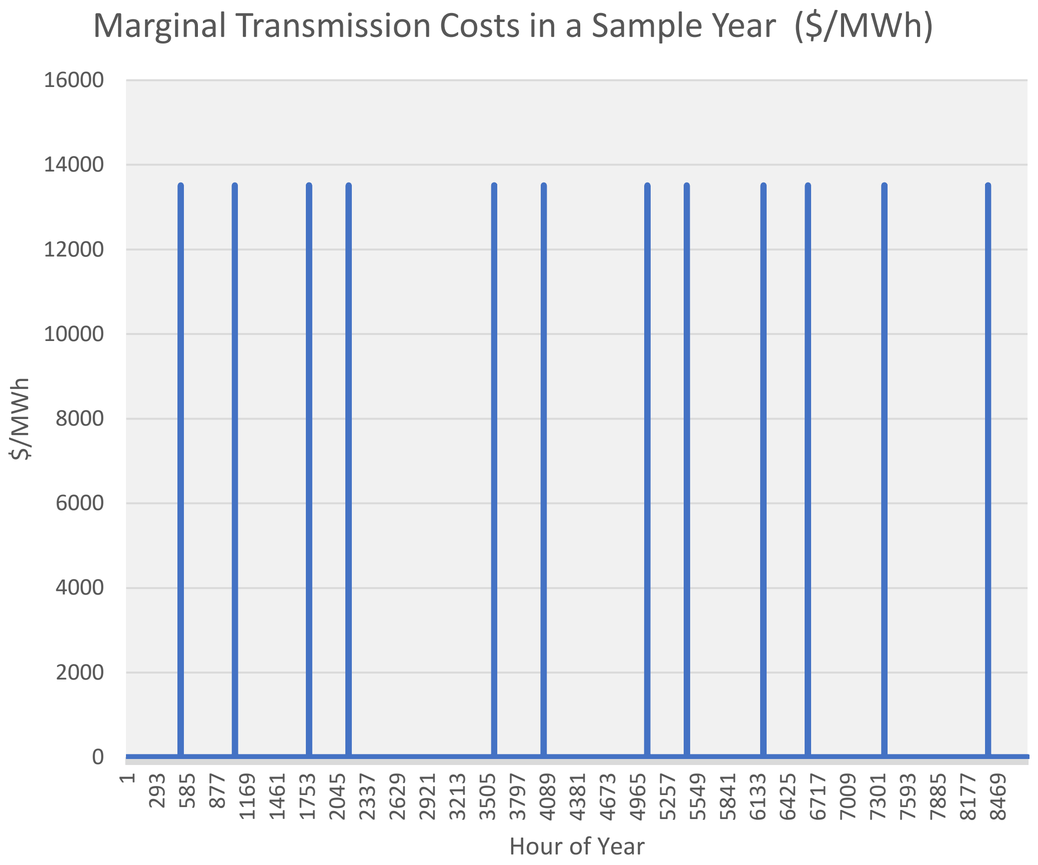
Wholesale capacity costs are allocated to the system peak hour, by ISO-NE

- ISO-NE Forward Capacity Market Costs are allocated to load based on contribution to the system's annual peak hour. (Tariff III.13.7.5.2)
- Reducing consumption in the system peak hour, reduces LSE capacity costs for the full Capacity Commitment Period. (Tariff III.13.7.5.5)
- Thus, marginal cost of capacity in the peak hour equals the full, annual cost of that product.
  - i.e., costs are $0 in 8759 hours per year and approximately $100,000/MWh in one hour.



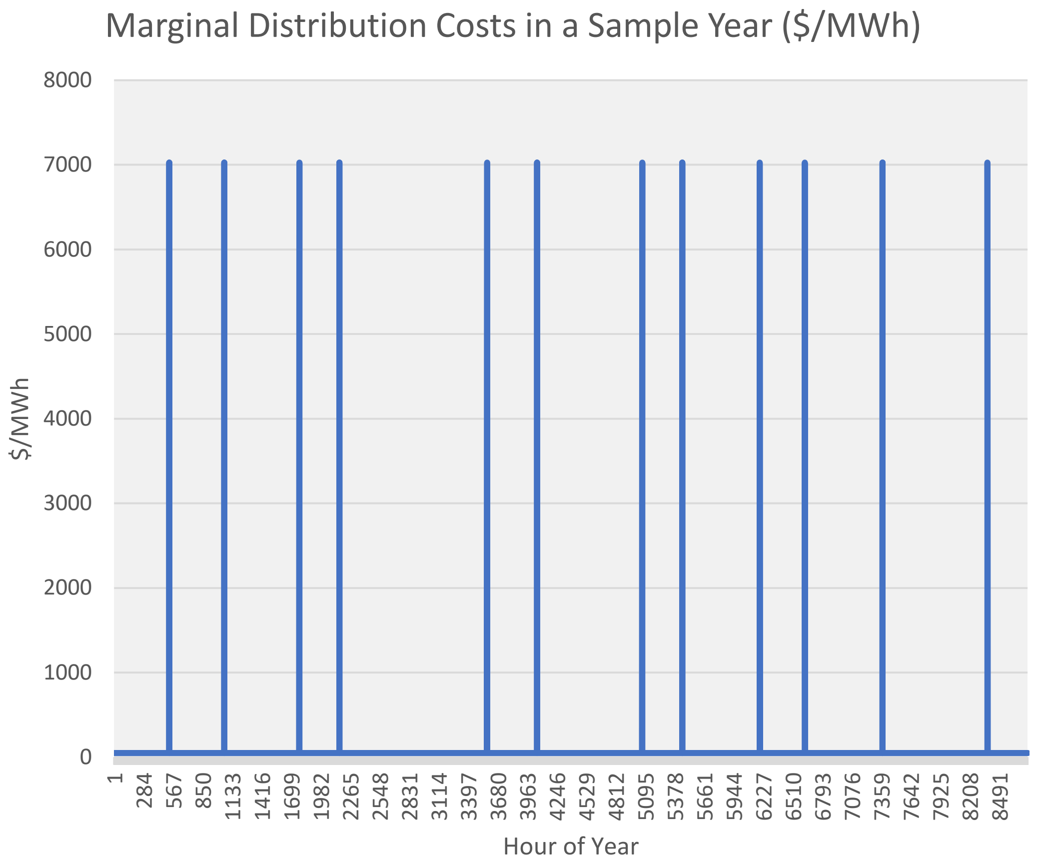
Transmission costs are allocated to the system peak hour, by ISO-NE

- ISO-NE allocates Regional **Transmission** Service ("RNS") costs to load, based on an LSE's share of monthly system peak. (Section II.21.2 of the ISO-NE Open Access Transmission Tariff.)
- Reducing demand on any monthly system peak reduces transmission costs for the LSE, thus the marginal cost of transmission equals the RNS rate.
- RNS currently costs approximately $11,000/MW-month (ISO-NE Schedule 1 Rate). LNS rates add another $2,500.
    - Or, $13,500/MWh for each of the 12 hours a year in which it is assessed, and zero in all other hours.
    - Average Cost = $31/MWh



For this analysis, AGO assumes 25% of general and distribution plant costs are time-varying.

- Review of Eversource's 2019 FERC Form 1 (p206-7) suggests that approximately 25% of its distribution costs are time-varying.
  - Distribution Plant and General Plant total about $7bn
  - AGO assumes that about $1.75bn of plant costs are time-varying.
    - Station Equipment, $1bn (Assumed 100% time-varying)
    - Transformers, $0.7bn (Assumed 50% time-varying)
    - Conductor/Conduit/Poles, $4bn (Assumes 10% time-varying; e.g. feeders 100%)
- AGO assumes that the time-varying costs are allocated to the monthly system peak.
  - In peak hours, marginal cost = $7,025/MWh
  - Otherwise, distribution cost = $48/MWh
  - Average Cost = $64/MWh



Many methods to develop time-varying distribution rates.

- Liberty Utilities (NH) developed a method which assumes that hourly distribution cost is a function of load.
- PSNH (NH) calculated representative bulk distribution system TOU rates by assessing the hours when these facilities were observed to peak.
- Baltimore Gas & Electric (MD), Schedule RD, allocates most distribution cost to peak period for their EV TOU.
  (Peak Rate: 11.78¢/kWh; Off-Peak Rate: 2.29¢/kWh)
- Southern California Edison (CA) split distribution marginal costs into peak- and grid-related categories then applied a peak-load risk factor methodology to determine hourly allocations.

Appendix 2:
Algorithmic Rate Design

Rationale of Algorithmic Rate Design

- Designing TOU rates can be challenging.
  - Into how many seasons and periods should the year be divided?
  - What months should be in which season, and which hours in which period?
  - How different should prices be between peak and off-peak periods?
- Range of design considerations, evaluation metrics, and embedded policy goals, often lead regulators to adopt “close-enough” rates.
- Algorithmic rate design offers a path forward because it provides an objective method to:
  - *Discover* high quality, economically efficient rates.
  - *Compare* rates with different numbers of seasons and periods.
- Whitepaper describing and applying the methodology available

Efficient TOU Rates in 7 Easy Steps

1. Generate a random set of ***S*** seasons and ***P*** periods.
   - Seasons & Periods are contiguous, mutually exclusive, and collectively exhaustive.
2. Calculate TOU Price for each ***P*** in each ***S***, where the TOU **Price** equals the load-weighted average hourly price
   - Indifference achieved because a customer's bill under flat and TOU rates are identical for baseline loads.
   - Ensures revenue sufficiency, but not necessarily a high-quality rate.
3. Calculate TOU specification's Goodness-of-Fit using common Root Mean Squared Error ("RMSE") metric. Better goodness of fit means less deviation between the RT and TOU prices.

$$RMSE = \sqrt{\frac{1}{h}\sum_{h=0}^{H}(Price_{h,realtime} - Price_{h,TOU})^2}$$

4. Check if adjacent TOU specifications better goodness-of-fit, using process from steps 2-3.
   - Adjacent means a 1-hour or 1-month change somewhere in to the TOU specification.
5. Move to adjacent specification if error is lower.
6. Repeat Steps 4-5 until there is no better specification. This is a local optimum.
7. Repeat Steps 1-6 many times using different starting specifications to find global optimum.

Example TOU vs RT Price Duration Curve